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Security of supply in a carbon-free electric power system: The case of Iceland

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HIGHLIGHTS

- Medium- and long-term security of decarbonized power supply in Iceland is analyzed.
- Illustrative example of decarbonized power system in the face of zero marginal cost.
- Bilateral contracts with curtailment clause are included into a hydrothermal model.
- Transmission upgrades improve security of supply and defer generation investments.
- Renewable technologies alone can provide outstanding levels of security of supply.

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ABSTRACT

Security of supply and progressively climate change are guiding countries' energy policy worldwide. Iceland is a paradigmatic example of gaining energy independence and decarbonizing the power sector while meeting its growing demand. In this paper, we focus on some of the main generation and transmission expansion alternatives that the country is considering for the next decade in an environment dominated by an increasing demand and a generation mix with virtually zero variable cost. We assess the medium- to long-term dimensions of security of supply as determinants of the system configuration and resources utilization. Based on a stochastic hydrothermal scheduling model that includes DC power flows and generation expansion decisions, our analysis indicates that hydro, geothermal and wind renewable resources are more competitive than fossil fuels, while demand flexibility can also contribute to gain security of supply at comparable costs. In addition, our methodology incorporates a detailed bilateral contracting structure typically used by Icelandic generators and consumers to agree on power prices and negotiated curtailments. The modeling and security evaluation could be of interest in other countries and regions where inflexible thermal generation and hydro resources create a market characterized by prices that are close to zero during long periods, but spike when resources are scarce.

1. Introduction

Iceland is a sparsely populated country—about 327,000 inhabitants in 2014—whose electricity demand, 17.6 TWh in 2014, places Iceland on the top of the global ranking of electricity consumption per capita, according to the World Bank database [1]. The Icelandic 54 MWh electricity consumption per capita more than doubles that of Norway, which is second in the ranking. Cheap and reliable electricity have attracted energy-intensive consumers, such as aluminum, silicon and ferrosilicon industries, and data centers. In addition, Iceland offers 100% renewable electricity and high quality of supply, and its power system is not connected to any other system due to its geographical position (1000 km to Scotland and 2500 km to Labrador Peninsula by sea). Iceland is undoubtedly an example for (mostly isolated) countries or areas that pursue a reliable and decarbonized energy system.

Access to a secure energy supply is essential for a good standard of living in modern societies. Energy scarcity and outages can have a severe adverse impact on businesses, schools, homes, finances, and telecommunications, and can lead to public safety incidents. According to the International Energy Agency [2], energy security is “the uninterrupted availability of energy sources at an affordable price”. Gracceva and Zeniewski [3] define a secure energy system as one which evolves over time with an adequate capacity to satisfy the energy service needs of its users under any circumstance.

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Nomenclature

Indexes

P,p	period
N,n	load level
G,g	power plant
$X(g)$	candidate expansion for power plant g
E,e	reservoir
$H(e)$	hydro plants of reservoir e
$U(e)$	upstream hydro plants of reservoir e
$R(e)$	upstream reservoir of reservoir e
S,s	hydro scenario
$A(s,p)$	scenario ancestor of hydro scenario s in period p
i,j	node
$L(i,j)$	transmission line connecting nodes i and j
$Y(g,i)$	location of power plant g at power bus i
$K(L)$	transmission corridor containing line l
T,t	consumer
B,b	level of curtailment

Parameters

D_{tipn}	load demand by consumer at node, period and load level [MW]
CQ_{tb}	cost of load curtailment by consumer and curtailment level [$/MWh]
CP_{tb}	maximum instantaneous curtailment (power) by consumer and level [%]
QE_{tb}	maximum annual curtailment (energy) by consumer and level[%]
QA_{tb}	maximum expected curtailment (energy) by consumer and level [%]
Dur_{pn}	duration of period and load level [h]
W_s	probability of hydro scenario [p.u.]
Q_g^{max}	maximum power production of power plant [MW]
Q_g^{min}	minimum power production of power plant [MW]
QX_g	capacity expansion of power plant [MW]
CV_g	variable production cost of power plant [$/MWh]
CS_g	startup cost of power plant [$]
CX_g	annualized cost of expansion of power plant [$/MW-yr]
$F_{H(e)}$	production function of hydro plant [MWh/hm^3]
$HO_{H(e)}$	head effect (intercept) in hydro plant [MW]
$HS_{H(e)}$	head effect (slope) in hydro plant [MW/hm^3]
Q_e	maximum water reserve in reservoir [hm^3]
Q_{ef}	final reservoir level [hm^3]
I_{esp}	natural water inflows to reservoir for hydro scenario in period [hm^3]
S^B	base power [MW]
$R_{L(i,j)}$	resistance of line [p.u.]
$X_{L(i,j)}$	reactance of line [p.u.]
$K_{L(i,j)spn}$	losses coefficient of line in scenario at period and load level [p.u.]
$Q_{L(i,j)}$	maximum capacity of line [MW]
$Q_{K(L)}$	maximum capacity of corridor [MW]

Variables

u_{gspn}	commitment of power plant in hydro scenario at period and load level {0,1}
y_{gspn}	startup of power plant in hydro scenario at period and load level {0,1}
z_{gspn}	shutdown of power plant in hydro scenario at period and load level {0,1}
x_g	expansion of power plant {0,1}
q_{gspn}	production of power plant in hydro scenario at period and load level [MW]
θ_{ispn}	voltage angle
$f_{L(i,j)spn}$	power flow of line in hydro scenario at period and load level [MW]
$fp_{L(i,j)spn}$	positive flow from i to j in hydro scenario at period and load level [MW]
$fn_{L(i,j)spn}$	positive flow from j to i in hydro scenario at period and load level [MW]
l_{ispn}	power losses allocated to node in hydro scenario at period and load level [MW]
nsp_{tbispn}	curtailment by consumer and level at node in hydro scenario at period and load level [MW]
r_{esp}	water reserve of reservoir in hydro scenario at end of period [hm^3]
s_{esp}	water spillage of reservoir in hydro scenario at period [hm^3]

Cases

RC	Reference Case
HO	Highlands Option – Network expansion
IO	Interregional Option – Network expansion
DO	Diesel Option – Network expansion, sensitivity analysis
WO	Wind Option – Generation expansion
NWO	Non-Wind Option – Generation expansion
GO	Gas Option – Generation expansion, sensitivity analysis
CO	Curtailment Option – Generation expansion, sensitivity analysis

Security of supply has been a major guiding factor for energy policy worldwide. In addition, climate change is increasingly conditioning energy policies. Most countries have pledged to limit CO_2 emissions by increasing renewable generation, energy efficiency, and other measures. How to maintain or even gain security of supply while decarbonizing the energy sector has also motivated our analysis. As mentioned above, Iceland is an example of a country that is gaining energy security and progressively decarbonizing its energy sector. Yet the future path is not clear and Iceland continues to face an increasing energy demand that may compromise its security of supply. The electricity demand is expected to continue increasing during the next decade—more than 2% annually for household and commercial segments and up to 5.4 TWh for energy-intensive ones.[1] Therefore, Iceland faces the challenge of accommodating roughly 6.9 TWh of new demand, about 40% of the current demand, by 2030.

In this paper, we analyze and assess the options, at the power generation and transmission levels, that are currently under discussion in Iceland to achieve high levels of security of energy supply during the next decade. Nevertheless, this contribution should not only be restricted to Iceland, but put into the broader context of the many countries and areas that will find themselves in similar circumstances in the near future; that is, pursuing security of supply while decarbonizing their energy system. In particular, the described model is of interest to systems with relevant hydro resources and inflexible thermal (e.g., nuclear or geothermal) power plants, which creates the conditions for zero-price periods and price spikes.

This price volatility has led Icelandic producers and consumers to negotiate bilateral contracts with which both parties value zero-cost producing resources. Although our approach focuses on the

[1] Projections provided by Orkustofnun and Landsvikjun, the Icelandic energy regulator and main power company, respectively.

transmission level, our model includes this bilateral contracting structure that may also be of interest for distributed systems, which are still testing their market and pricing mechanisms (e.g. [4]).

At either the distribution or transmission level, current literature confirms the interest of the techno-economic assessments of energy systems that are transitioning from fossil- to renewable-based generation–for example, an island in the Mediterranean Sea [5], an island in the Atlantic Ocean [6], an island in the Indian Ocean [7], Hong Kong [8], Denmark [9], Norway [10], Ireland [11], Macedonia [12], Portugal [13], South Korea [14], China [15], Australia [16] or the U.S. [17]. Our paper looks a step further since Icelandic electricity is already 100% renewable. We present the case of a country that still faces energy security problems and questions whether to return to fossil-fuel generation. Our approach deals with the aftermath of achieving a 100% renewable system. The paper shows that maintaining a fully renewable system is not trivial and requires further analysis.

2. Context

2.1. Icelandic electric power system

Iceland has unique characteristics. All electricity comes from renewable energy sources, mainly hydro and geothermal. It has no nuclear, coal, or gas infrastructure. Iceland is an island whose transmission network is disconnected from the rest of the world, and hence cannot participate in the electricity trade with neighboring countries. In addition, the aging transmission network frequently reaches its tolerance limits. Sporadic preventive curtailments occur when the expectation of future water inflows is low. Because of these distinctive features, ensuring security of electricity supply in an economic manner while meeting environmental goals is a prevalent concern in Iceland.

Iceland is blessed with a significant amount of exploitable geothermal, hydro, and wind resources. Nowadays, only 13% of its primary energy comes from fossil fuels, mainly oil for transportation. The power sector is completely decarbonized, and remarkably, the transformation occurred while the demand was steeply increasing from the 1970s to the (particularly high-demand) 2000s. Security of supply improved as long as Iceland displaced fossil fuels and gained energy independence. However, the current challenge, due to expected demand growth, brings back dilemmas from the past such as the return to fossil fuels.

Population is growing and more energy-intensive industries and data centers are likely to land in Iceland, as long as electricity prices remain low and delivery remains reliable. Furthermore, the full decarbonization of the energy system requires the renovation and substitution of the transportation fleet by electric or hydrogen vehicles and vessels. Past studies have examined the Icelandic energy system up to a certain extent. Christensen [18] conducted a SWOT (strengths, weaknesses, opportunities and threats) analysis and provided some policy recommendations, although he did not dive into the techno-economic aspects of the energy system. Hreinsson [19] explored the connection of Iceland to the UK by considering the hydro system, but by representing the transmission network by a single node. Our work delves into these and other issues, by quantitatively analyzing the country security of supply based on a detailed model of its electric power sector that includes a representative and accurate version of its main transmission system. Our assessment contributes to the understanding of the Icelandic system by exploring the potential generation investment and network reinforcement options that are currently under discussion.

The Icelandic geography has determined to a great extent the existing high-voltage transmission network configuration, which circumvents the island. This oval- or ring-shaped network is mainly comprised of 132 kV lines, which have been reinforced with new 220 kV and 400 kV (still operated at 220 kV) lines in the southwestern and eastern regions where most of the consumption is located. This configuration creates stability problems, since the 132 kV lines connecting the southwestern and eastern regions sometimes cannot handle the power flows. In addition, some radial 132 kV and 66 kV transmission lines hang from the oval-shaped transmission network to deliver energy to public utilities (i.e. households and smaller industries) outside the ring.

Similarly, the Icelandic geological formations have mostly determined the location of the power plants. The largest hydropower facilities are located in the southwestern and eastern regions. The geothermal power plants are mainly located in the southwestern and northern regions. Although the power-intensive consumers are close to the southwestern, northern, and eastern generation sites, the transmission network still plays a relevant role in conveying power from the east to the west, and vice versa, since the climatic conditions sometimes require such flows (e.g., when extreme cold weather defers the glacier melting in the East).

Another relevant aspect of the Icelandic power system is the difficulty in determining the electricity price. An organized power market does not exist and bilateral contracts are the main tool for trading electricity. If a market were to exist, according to the marginal-cost pricing theory [20], the geothermal power plants would submit zero-price bids as baseload units with reduced flexibility and variable cost, and the hydropower plants would submit bids corresponding to their short-term water value [21], which would be equal to zero when hydro resources are, or are expected to be, abundant and extremely high when scarce. Since power-intensive consumers are not willing to be subject to weather uncertainty, and generation companies cannot expect to recover their investment costs during periods of scarcity only, both parties agree on long-term agreements from 20 to 40 years. The electricity price is mainly indexed to some industrial product, e.g., aluminum. The agreements also include some flexibility products—named secondary and buyback energy—that allow generation companies to partially curtail power-intensive consumers during times of energy scarcity in exchange for a fee. Depending on the level of curtailment, each product has a corresponding fee, whose combination determines a two-step price before reaching extremely high prices when water is scarce.

2.2. Security of supply

As previously mentioned, a secure energy system evolves over time and achieves an adequate capacity to absorb uncertain events, so that the system is able to continue satisfying the energy service needs of its users with acceptable changes in their quantities and prices. Although the delivery of electricity takes place in real time, different agents (regulators, investors, systems operators, producers and consumers) have to make multiple decisions, which involve diverse technologies and energy resources, at different time scales: from several years to seconds. We hence distinguish the four temporal dimensions of security of supply [22]:

- Strategic energy policy, with a long- to very long-term decision horizon (at least five years), determines the long-term availability of energy resources, including physical existence and reliable supply that meets environmental constraints, affordable price, and acceptable energy dependence of the country.
- Adequacy, with a long-term decision horizon (from few to less than five years), ensures the existence of enough available capacity, both installed and/or expected, to meet the forecasted demand.
- Firmness, with a short- to medium-term decision horizon (within a year), concerns the availability of supply infrastructure when needed. It mainly depends on the operation planning activities of the already installed capacity: maintenance schedules, fuel supply contracts, hydro reservoir management, units cycling, etc.
- Security, which involves real-time decisions, is achievable through the readiness of existing and functioning generation and network capacity to respond in real time to load requirements when needed.

Although a reliable supply results from a combination of security, firmness, and adequacy under the guidance of a strategic energy policy,

in this paper we focus only on the firmness and adequacy dimensions. These two dimensions mostly determine the system topology and guide the utilization of the available resources. Our assessment also embeds strategic energy policy, which is implicitly considered when determining the projected future demand and the analyzed strategic options[2] for achieving high levels of security of supply. Although more general assessment frameworks are found in the literature, e.g., [23-26], we focus on the techno-economic assessment of the electric power system as a central piece of future energy systems and of Iceland in particular.

With this framework in mind, we have identified three areas of concern within the Icelandic transmission and generation systems:

1. Generation adequacy. Although there is no shortage of capacity today, the lack of sound and clear investment signals, as well as the increased emphasis on environmental protection, is discouraging required investments to face future demand.
2. Transmission adequacy. The transmission network is becoming too outdated to accommodate the increasing demand. In 2014, inter-regional power flows, from both east to west and west to east, exceeded security-monitoring limits (i.e. stability limits) 28% of the time. Moreover, the existing options under consideration for strengthening the network face environmental concerns.
3. Generation firmness. Hydro accounts for 71% of total electricity generation and its firmness depends on hydro inputs, weather conditions and reservoir management decisions. This is a very relevant issue in the context of a hydro-dominated system.

In addition, real-time network stability problems jeopardize transmission security. However, the current stability problems are expected to disappear with the proposed network development and reinforcement plans. Therefore, transmission security is strongly tied to transmission adequacy in Iceland.

3. Simulation model

We have simulated the functioning of the Icelandic power system by using a stochastic medium-term hydrothermal scheduling model that optimizes the yearly generation dispatch for a tree-based representation of possible hydro scenarios. This type of model is a valuable tool for coordinating the thermal dispatch with the within-year or multiyear reservoir management. In general, the literature distinguishes between two families of stochastic hydrothermal models: stochastic dual dynamic programming (SDDP) and stochastic linear/non-linear programming (SLP/SNLP). Although both model families must result in the same solution for the same input data, the big difference between both is the solving algorithm to deal with numerous hydro scenarios. SDDP models are particularly useful when the number of hydro scenarios is very large. They have been widely used in hydro-dominated power systems, e.g. Brazil [27], New Zealand [28], Spain [29], and Iceland [30]. Due to the relatively small number of hydro scenarios in our analysis (about 50), we solve a SLP model by composing a scenario tree [31] and formulating its deterministic equivalent problem. These models have also been applied to real instances [32,33]. We refer the reader to a classical reference [34] and a new one [35] for further details on hydrothermal scheduling models.

Our model expands the capabilities of traditional hydrothermal scheduling models by introducing the transmission network for calculating the equivalent DC power flows and by computing the expansion in generation capacity. We also include a linearized version of the head effect to accurately capture the output power loss when the hydro reservoir level decreases. Moreover, the model incorporates the bilateral contracting structure that prevails in Iceland due to the impossibility of establishing a traditional spot market in the context of zero variable cost technologies. All previous additions have created a valuable mathematical tool to analyze energy security in systems where hydro and renewables (i.e. zero variable cost technologies) play or will play a predominant role.

3.1. Mathematical formulation

The rest of this section describes the hydrothermal model, which we used for analyzing the considered options for guaranteeing the electricity security of supply in the future. The notation is found at the beginning of the paper.

The model minimizes the total annual expected costs, which include the production costs, the thermal plant startup costs, the load curtailment costs, and the generation investment annuity costs.

$$\min \sum_{s,p,n} W_s \left(Dur_{pn} \sum_{g} CV_g q_{gspn} + \sum_{g} CS_g y_{gspn} + \sum_{t,b,i} Dur_{pn} CQ_{tb} nsp_{tbispn} \right) + \sum_{g} CX_g x_g \quad (1)$$

The nodal energy balance equation guarantees that the nodal production in each node meets the nodal demand and the net (in and out) flows through the set of transmission lines connected to this node. The balance equation also considers the possibility of load curtailment and transmission losses.

$$\sum_{g \in Y(g,i)} q_{gspn} + \sum_{t,b} nsp_{tbispn} \geqslant \sum_{t} D_{tipn} + \sum_{j} f_{L(i,j)spn} - \sum_{j} f_{L(j,i)spn} + l_{ispn} \quad \forall\, i,s,p,n \quad (2)$$

The equivalent DC formulation describes the power flows.

$$f_{L(i,j)spn} = S^B \frac{\theta_{ispn} - \theta_{jspn}}{X_{L(i,j)}} \quad \forall\, i,j,s,p,n \quad (3)$$

The power losses in a transmission line are deemed to be proportional to the absolute value of power flow around the considered operation point, and split between the two adjacent nodes.

$$f_{L(i,j)spn} = fp_{L(i,j)spn} - fn_{L(i,j)spn} \quad \forall\, i,j,s,p,n \quad (4)$$

$$l_{ispn} = 0.5 \left(\sum_{L(i,j)} K_{L(i,j)spn} (fp_{L(i,j)spn} + fn_{L(i,j)spn}) + \sum_{L(j,i)} K_{L(j,i)spn} (fp_{L(j,i)spn} + fn_{L(j,i)spn}) \right) \quad \forall\, i,s,p,n \quad (5)$$

$$K_{L(i,j)spn} = 2S^B \frac{1 - \cos(\theta_{ispn} - \theta_{jspn})}{|f_{L(i,j)spn}|} \frac{R_{L(i,j)}}{\sqrt{R_{L(i,j)}} + \sqrt{X_{L(i,j)}}} \quad (6)$$

As Eq. (6) is non-linear, we obtain the linear coefficient of power losses after an initial simulation in which we disregard the power losses, i.e. we disregard Eqs. (4) and (5). Once we compute the losses coefficient considering the power flow and voltage angle values from the initial simulation, we include Eqs. (4) and (5) and the calculated losses coefficient in the problem formulation and run the model again. We have empirically observed that the losses coefficients maintain relatively constant in successive iterations. Nevertheless, this iterative process could increase in accuracy if desired.

The level of load curtailment is limited by a maximum percentage of both the instantaneous power demand and the annual energy consumption.

$$nsp_{tbispn} \leqslant QP_{tb} D_{tipn} \quad \forall\, t,b,i,s,p,n \quad (7)$$

[2] Based on Orkustofnun database; the official Icelandic Master Plan concerning power plant construction (www.ramma.is); and Landsnet, the system operator, network development plan.

$$\sum_{s' \in A(s,p),p,n} Dur_{pn} nsp_{tbis'pn} \leqslant QE_{tb} \sum_{p,n} Dur_{pn} D_{tipn} \quad \forall\, t,b,i,s \tag{8}$$

The bilateral agreements between power-intensive consumers and power generators usually include a maximum energy curtailment over a moving average, e.g. five years. The moving-average length is not standard, but results from the negotiation process. The power generator hedges the risk from multiannual hydrological cycles, while the consumer is protected from experiencing large curtailments every year. This clause actually limits the energy curtailment over the agreement horizon. Without loss of accuracy, we formulate this clause by limiting the expected energy curtailment over all hydro scenarios.

$$\sum_{s,p,n} Dur_{pn} nsp_{tbispn} \leqslant QA_{tb} \sum_{p,n} Dur_{pn} D_{tipn} \quad \forall\, t,b,i \tag{9}$$

The maximum production is limited by the maximum available capacity.

$$q_{gspn} \leqslant Q_g^{max} + QX_g x_g \quad \forall\, g,s,p,n \tag{10}$$

The maximum and minimum production of the power plant is also subject to the commitment of the power plant. The formulation also incorporates the startup and shutdown decisions.

$$q_{gspn} \leqslant (Q_g^{max} + QX_g) u_{gspn} \quad \forall\, g,s,p,n \tag{11}$$

$$q_{gspn} \geqslant Q_g^{min} u_{gspn} \quad \forall\, g,s,p,n \tag{12}$$

$$u_{gspn} + u_{gsp(n-1)} = y_{gspn} + z_{gspn} \quad \forall\, g,s,p,n \tag{13}$$

The water inventory equation establishes that the reserve level of the reservoirs at the end of a period is computed as the reserve level at the beginning of the period plus the period inflows minus the hydro reservoir release. The period inflows are comprised of the natural inflows as well as the upstream hydro plant water releases or spillages.

$$r_{esp} = \sum_{s' \in A(s,p)} r_{es'(p-1)} + I_{esp} - s_{esp} + \sum_{e' \in R(e)} s_{e'sp} - \sum_{g \in H(e),n} Dur_{pn} q_{gspn}/F_g + \sum_{g \in U(e),n} Dur_{pn} q_{gspn}/F_g \tag{14}$$

We approximate the head effect with a linear constraint that reduces the maximum production of a hydro power plant as the corresponding reservoir gets depleted.

$$q_{gspn} \leqslant HO_g + HS_g r_{esp} \quad \forall\, g \in H(e),e,s,p,n \tag{15}$$

We establish that the final reservoir level of each scenario must be greater than a threshold. Since the time scope of the simulation is one year, we fix the initial reservoir level to the same value.

$$r_{esp} \geqslant Q_e^f \quad \forall\, e,s,p \in F(p) \tag{16}$$

3.2. Use of the model

In summary, we have extended the traditional hydrothermal coordination scheduling model to include bilateral contracts with interruptible clauses, DC power flows through the transmission network, and generation expansion decisions. The model also considers the uncertainty of hydro inflows I_{esp} through a stochastic scenario tree, which is composed by using the clustering technique as described in [31] and real inflow data for every scenario since 1951. We have developed this mathematical tool to assess the adequacy and firmness of any hydrothermal system, although we illustrate its utilization with the Icelandic case.

Our assessment also embeds the strategic energy policy as that corresponding to the projected future demand, the analyzed future generation, and the network expansion scenarios that portray several strategic options for the system development, as detailed in next section. Broadly speaking, each system expansion scenario is defined by an explicit network reinforcement plan (two options), as envisaged by the system operator, and by a set of candidate generation (hydro, geothermal and wind) power plants, as enumerated in the official Icelandic Master Plan. The model provides the optimal generation expansion decisions—through the decision variable x_g —for each system expansion scenario. The model also provides, among other results, the total load curtailments and total costs. Through the comparison of these main outputs, we assess the system expansion scenarios and derive some recommendations.

4. System expansion scenarios description

The options under discussion nowadays in Iceland include two transmission reinforcement options and about twenty hydro, geothermal, and wind projects. In addition, the Icelandic stakeholders are evaluating the installation of gas-fired power plants and diesel groups as intermediate solutions for mitigating network failures. Negotiating an increment of the maximum curtailment threshold is another possibility that may defer investments in new generation capacity. In accordance with these options, we have established the following roadmap:

- Reference case, year 2020. We analyze the current system in addition to the already approved generation assets and network reinforcements that will be available by 2020 in the so-called Reference Case (RC).
- Network expansion, year 2020. The generation system does not require any additional investments, besides those already approved, by the year 2020, so we evaluate the network reinforcements alone for that year. This study allows us to evaluate and conclude which is the best transmission reinforcement option independently of how the generation system evolves. The two reinforcement options are: (1) the Interregional Option (IO) that would complete the oval-shaped transmission network with 220 kV lines; and (2) the Highlands Option (HO) that would incorporate a new link, connect the northern and southern regions, and transform the oval- into an infinity-shaped network. In addition, we perform a sensitivity analysis in which diesel power stations (DO) are installed instead of reinforcing the network to reduce load curtailments.
- Generation expansion, year 2030. Since we subtract wind production from power demand, we distinguish two cases when deciding the hydro and geothermal investments: (1) the Wind Option (WO), and the Non-Wind Option (NWO). This distinction allows us to evaluate deploying wind in comparable terms to a hydro or geothermal project. We combine both cases with the previous network reinforcement options, and conduct four analyses: WO-IO, WO-HO, NWO-IO, and NWO-HO. We simulate all cases for year 2030, when meeting the increasing demand requires new generation investments. We also perform two sensitivity analyses in which we replace the most expensive new power plant by a gas-fired power plant (GO) of similar characteristics or additional negotiated curtailments (CO).

The Icelandic stakeholders have been assessing an additional system network expansion project within the context of the possible interconnection of Iceland to the UK through a submarine cable. However, this alternative is out of the scope of this paper.

4.1. Reference case

We have represented the transmission system with 20 nodes that group real substations (see Fig. 1). The simplified network includes 21 equivalent transformers and transmission lines (Table 1). Due to network stability problems, there are more stringent limits applied to the power flows through some corridors, i.e., groups of lines (Table 2). The generation portfolio consists of 6 geothermal power plants (Table 3)

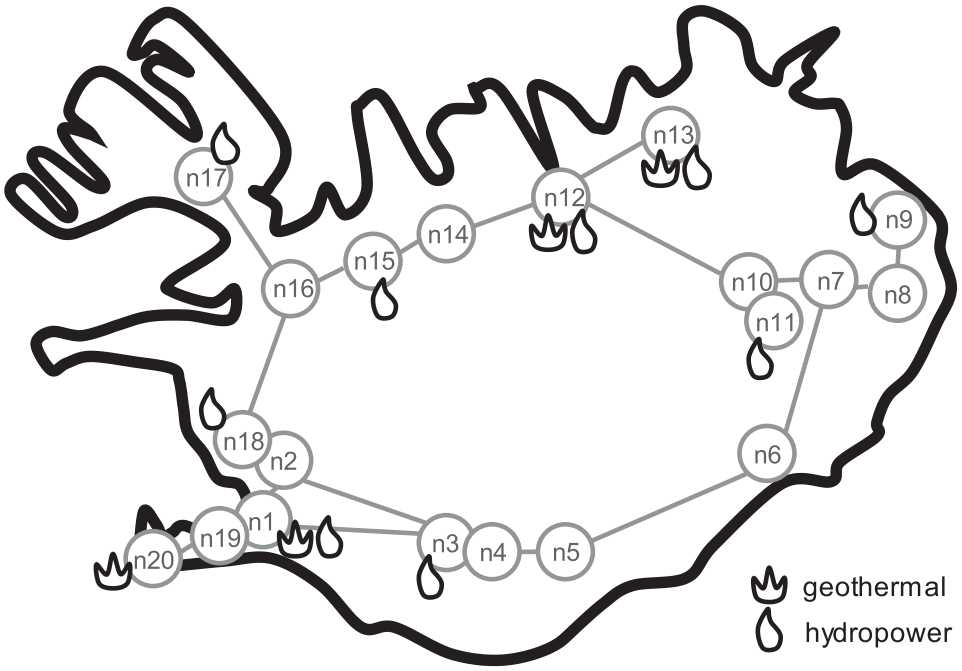

Fig. 1. Stylized representation of the Icelandic transmission and generation system.

Table 1
Transmission network description. Lines and transformers connecting nodes i and j.

Line $L(i,j)$	Node i	Node j	Resistance [p.u.] $R_{L(i,j)}$	Reactance [p.u.] $X_{L(i,j)}$	Capacity [MW] $Q_{L(i,j)}$
L1	n1	n2	0.009	0.053	304
L2	n1	n3	0.004	0.030	889
L3	n1	n19	0.002	0.064	184
L4	n2	n3	0.004	0.047	963
L5	n2	n18	0.003	0.091	134
L6	n3	n4	0.002	0.108	100
L7	n4	n5	0.033	0.179	85
L8	n5	n6	0.078	−0.008	100
L9	n6	n7	0.064	0.292	85
L10	n7	n8	0.001	0.001	190
L11	n8	n9	0.001	0.001	255
L12	n7	n10	0.013	0.050	155
L13	n10	n11	0.002	0.080	150
L14	n10	n12	0.108	0.485	100
L15	n12	n13	0.286	0.808	37
L16	n12	n14	0.086	0.214	80
L17	n14	n15	0.015	0.075	100
L18	n15	n16	0.015	0.074	150
L19	n16	n17	0.000	0.000	30
L20	n16	n18	0.086	0.394	150
L21	n19	n20	0.008	0.037	356

and 15 hydro power plants (Table 4). Hydropower plants h12 to h15 are equivalent plants that result from grouping smaller hydro units. The geothermal power plants normally operate in baseload; hence the minimum and the maximum output are equal, and the variable and start-up costs are set to zero.

Table 2
Stability constraints. Groups of lines and flow direction from node i to node j.

Corridor $K(L)$	Line from node i to node j	Capacity [MW] $Q_{K(L)}$
L7, L17	n4 → n5 n15 → n14	130
L12, L18	n10 → n7 n15 → n16	180
L11	n8 → n9	90

Table 3
Geothermal portfolio. The power plant is located at node i.

Thermal generator g	Node i	Capacity [MW] Q_g^{max}
g1	n1	120
g2	n1	300
g3	n20	75
g4	n20	100
g5	n12	60
g6	n13	90

The largest hydropower complex in Iceland possesses some particular characteristics that complicate its modeling. The actual facility is comprised of two parallel reservoirs (e81 and e82 in our formulation) that feed the same power plant. Depending on the amount of water that is provided by each reservoir, the maximum power plant output is different. In order to consider this effect, we have divided the actual power plant into two artificial power plants, h81 and h82. The hydropower plant h81 concerns the contribution of the small reservoir e81 alone. In addition, the reservoir e82 presents a head effect. We have approximated the head effect with an affine function, with $HO_{H(e)}$= 553 MW and $HS_{H(e)}$= 0.045 MW/hm^3 as intercept and slope, respectively.

We have captured most of the uncertainty of hydro inflows in the period 1951–2004 by generating a hydro scenario tree[3] [31]. Our simulation starts with the hydrological year in the 1st week of October. The tree opens two branches sequentially at the 2nd week of October, the 2nd week of November, the 1st week of April, the 1st week of May, the 1st week of June, and the 4th week of July, which total 54 hydro scenarios. These openings have been chosen to strike a balance between the size of the tree and the variability of hydro inflows that this tree is able to capture. Based on historical data, we assume that all reservoir levels must be at least at 95% of the maximum level at the start and end of the year in every scenario. This high set point is suitable for generating enough energy during the dry period, which in Iceland corresponds to the winter.

[3] The scenario tree could be made available upon request to the corresponding author.

Table 4
Hydropower portfolio. The power plant located at node i. Q_e shows the capacity of the associated reservoir to the power plant. Run-of-the-river power plants have no associated reservoir. U(e) and R(e) specifies the hydro power plant and associated reservoir upstream of the power plant.

Hydro generator g	Node i	Capacity [MW] Q_g^{max}	Production function [MWh/m^3] $F_{H(e)}$	Reservoir capacity [hm^3] Q_e	Upstream hydro plant $U(e)$	Upstream reservoir $R(e)$
h1	n1	90	0.181	–	–	–
h2	n3	90	0.158	e2, 1832	–	–
h3	n3	150	0.169	e3, 80	h2	e2
h4	n3	210	0.213	e4, 16	h3	e3
h5	n3	95	0.092	e5, 30	h4	e4
h6	n3	134	0.115	e6, 110	h5	e5
h7	n3	388	0.286	e7, 5	h6	e6
h81	n11	43	0.160	e81, 65	–	–
h82	n11	647	1.290	e82, 2088	h81	–
h9	n9	28	0.040	–	h82	e82
h10	n13	21	0.156	–	–	–
h11	n15	150	0.683	e11, 420	–	–
h12	n12	13	0.500	–	–	–
h13	n9	15	0.500	–	–	–
h14	n17	19	0.500	–	–	–
h15	n18	15	0.500	–	–	–

Table 5
Nodal demand as percentage of total demand.

	By 2020		By 2030	
	General	Power-intensive	General	Power-intensive
Total [GWh]	3.94	16.46	4.82	19.38
n1	44%	22%	47%	18%
n2	0%	36%	0%	30%
n3	9%	0%	7%	0%
n5	2%	0%	2%	0%
n6	1%	0%	1%	0%
n7	1%	0%	1%	0%
n8	1%	0%	1%	0%
n9	9%	0%	10%	0%
n11	0%	32%	0%	34%
n12	6%	4%	6%	3%
n13	2%	3%	2%	6%
n14	2%	0%	1%	0%
n16	3%	0%	2%	0%
n17	6%	0%	6%	0%
n18	7%	0%	7%	0%
n20	7%	3%	7%	9%

Table 6
Network reinforcement options. Lines and transformers connect nodes i and j. The '+' sing indicates the new voltage-upgraded nodes. "Project" specifies the option under which the line or transformer reinforcement occur.

Line $L(i,j)$	Node i	Node j	Resistance [p.u.] $R_{L(i,j)}$	Reactance [p.u.] $X_{L(i,j)}$	Capacity [MW] $Q_{L(i,j)}$	Project
L1	n1	n2	0.004	0.027	608	IO,HO
L5	n2	n18	0.003	0.091	150	IO,HO
L6	n3	n4	0.002	0.108	150	IO
L7x	n3	n5+	0.007	0.069	550	IO
L8x	n5+	n6+	0.016	0.152	550	IO
L9x	n6+	n7+	0.007	0.067	550	IO
L12x	n7+	n11	0.005	0.044	550	IO
L14x	n11	n12+	0.011	0.109	550	IO,HO
L21	n12	n12+	0.050	0.120	150	IO,HO
L22	n12	n15	0.056	0.250	178	IO,HO
L23	n12+	n15+	0.010	0.095	550	IO,HO
L24	n15	n15+	0.050	0.120	150	IO,HO
L18x	n15+	n16+	0.010	0.094	550	IO
L20x	n16+	n2	0.009	0.086	550	IO
L25	n3	n12+	0.016	0.160	550	HO

We have segmented the power demand into general and power-intensive demand. By using 2014 data, we have segmented the residential demand throughout the year into 520 load blocks: 52 weeks, weekdays and weekends, each with 5 load levels. For each day, we have defined 2 super peak hours, 2 peak hours, 14 baseload hours, 3 off-peak hours, and 3 super off-peak hours. We have used node n1 for the segmentation process because it accounts for 44% of total residential demand. We use the load profile in this node to define the residential demand in other nodes by multiplying the former by the corresponding demand share factor. In contrast, we assume that the power-intensive demand is flat. The nodal demand is shown in Table 5.[4]

We consider that all power-intensive consumers sign similar bilateral agreements with the generation companies. The agreements include two flexibility products. First, we define "secondary energy" as a product that allows curtailing up to 10% of instantaneous power, 5% of annual energy consumption, and 1% of the energy consumption during the contract duration. The secondary energy cost, which can be understood as a cost of non-served energy for just a limited amount of load, from the consumer's point of view, and a penalty or extra cost to the system that is implicit in the long term contract, is equal to the electricity price in Iceland, i.e., around $25/MWh according to Eurostat.[5] Second, we define "buyback energy" as a product that allows curtailing up to 5.3% of instantaneous power, and 1.2% of annual energy consumption. We estimate the buyback energy cost to be at $90/MWh, a value that roughly coincides with the cost of electric heating. Finally, we assume any other curtailment (i.e., additional non-served energy) to have a cost two orders of magnitude larger than the buyback energy cost.

4.2. Network expansion options

The system operator currently considers two main options to reinforce the network, which we have considered in our analysis. The interregional project would retrofit the current oval-shaped network by building a new 220 kV in parallel (IO code in Table 6). The estimated investment cost of this would amount to $575 million. The Highlands project would cross the island with an overhead AC or an underground DC line. This project would also retrofit the northern arc of the oval-

[4] The demand profile could be made available upon request to the corresponding author.

[5] http://ec.europa.eu/eurostat/statistics-explained/index.php/Electricity_price_statistics5.

Table 7
List of potential generation projects. We have estimated the LCOE by using the expected generation as shown in the national Master Plan.

Generator g	Node i	Capacity expansion [MW] QX_g	Production function [MWh/m^3] $F_{H(e)}$	Upstream hydro plant $U(e)$	Expansion cost [$/kW] CX_g	LCOE [$/MWh]
h2+	n3	45	–	–	103.70	–
h3+	n3	50	–	–	83.15	–
h4+	n3	70	–	–	86.25	–
h6+	n3	30	–	–	124.95	–
h7+	n3	40	–	–	97.20	–
h16	n3	93	0.037	h7	228.40	21.50
h17	n3	57	0.160	h16	233.10	27.60
h18	n3	140	0.349	h17	181.60	29.00
h19	n15	31	0.140	h11	235.45	39.00
h20	n17	35	0.917	–	280.35	48.10
h21	n17	55	0.611	–	227.30	48.20
g4+	n20	315	–	–	263.35	31.25
g5+	n13	90	–	–	263.90	32.20
g6+	n12	135	–	–	264.40	32.75
g7	n1	45	–	–	264.40	34.30
g8	n20	50	–	–	335.95	40.00
g9	n20	50	–	–	335.95	40.00
g10	n1	180	–	–	336.30	40.00
w1	n3	150	–	–	121.50	34.70
w2	n12	150	–	–	121.50	34.70
w3	n15	150	–	–	121.50	34.70

shaped network with 220 kV lines (HO code in Table 6). The estimated cost of the Highlands project would amount to $370 million for the overhead AC line and $616 million for the underground DC line. Both options raise environmental concerns. The IO project would require building a new line in the narrow path created by a glacier lagoon when discharging into the sea. The HO project would cross through untamed lands.

In light of this environmental concern, we consider an alternative to the previous reinforcements: installing diesel stations that could relieve network congestion and defer network reinforcements. The cost of a 13.5 MW diesel station amounts to about $11 million. Since the diesel price is above $150/MWh in Iceland, these stations would only help to mitigate non-negotiated curtailments when the system had already made use of all the available secondary and buyback energy.

4.3. Generation expansion options

The current generation system cannot cover the expected demand by 2030. If generation investments do not take place, the capacity margin will decrease to −7.4%, with 3.0 GW peak demand and 2.8 GW generation capacity. Iceland therefore needs new generation assets to face the increasing demand. Within the range of all available technologies, Iceland is blessed with numerous domestic and exploitable hydro, geothermal and wind resources. The Icelandic Master Plan concludes that the hydro potential amounts to 5.8 TWh, and the geothermal potential amounts to 9.0 TWh. These figures exclude those generation sites whose exploitation would cause severe and irreparable environmental damage. Although the Master Plan does not specify the wind potential, the already online wind farm, 1.8 MW large, reaches an outstanding 42% capacity factor.

Table 7 shows the list of considered generation projects. The potential production of the hydropower projects amounts to 3.5 TWh, while the geothermal projects could generate up to 7.3 TWh. This implies developing around 60% and 80% of the hydro and geothermal potential, respectively, according to the current Master Plan. Five hydropower and three geothermal projects (with '+' sign) correspond to potential repowering processes of already existing power plants. When we include wind in the generation portfolio, we consider that the three available generation sites are exploited at their full projected capacity. We assume that each wind farm produces 500 GWh, equivalent to a 38% capacity factor. We presume that the significant regulation capacity of the hydro power plants will easily accommodate wind uncertainty, and hence we use one single wind profile.[6] The aim of hydro repowering projects is to provide capacity during peak demand periods. As their energy production is low, their levelized cost of electricity (LCOE) is very high. Put differently, the hydro repowering projects will only occur when the power system faces capacity scarcity.

Table 8
Financial parameters. Lifetime in years. O&M costs as percentage of investment cost.

	WACC	Lifetime	O&M
Transmission	7.5%	40	1.5%
Diesel	7.5%	20	5.0%
Hydro	7.9%	50	1.5%
Geothermal	7.9%	35	3.0%
Wind	7.9%	25	4.0%
Gas	7.9%	30	4.0%

Since the public may be reluctant to exploit new natural resources due to potential environmental impacts, we have conducted two sensitivity analyses in which we replace the most expensive developed generation investment by:

- A gas-fired power plant with the same capacity as the replaced power plant. The whole project includes the construction of a floating storage and regasification unit. The cost of natural gas in Iceland amounts to $125/MWh, which includes a $30/ton CO_2 emission cost. At this cost, the gas-fired power plant will only generate when the system has first made use of all the secondary and buyback energy.
- Additional negotiated curtailments in the amount corresponding to the output of the replaced power plant.

Both options allow us to incorporate into the case study fossil fuels and demand-side strategies, and cover most of the options that are under discussion to achieve security of supply nowadays.

4.4. Numerical assessment

In order to compare the investment costs of assets with different

[6] The wind profile could be made available upon request to the corresponding author.

Table 9
Summary of main results.

	RC	HO	IO	DO	WO HO	WO IO	NWO HO	NWO IO	GO HO	CO IO
Secondary expected	0.89%	0.71%	0.66%	0.89%	1.00%	1.00%	1.00%	0.93%	1.00%	1.00%
Secondary frequency	Always	25/54	25/54	Always	25/54	25 /54	Always	Always	Always	25/54
Buyback frequency	27/54	1/54	1/54	27/54	4/54	4/54	3/54	1/54	39/54	32/54
Non-served frequency	3/54	Never	Never	Never	Never	Never	Never	Never	Never	Never
Annualized investment	–	$33 M $53 M	$49 M	$77 M	$136 M $156 M	$153 M	$126 M $146 M	$143 M	$144 M $164 M	$144 M

lifetimes, weighted average capital costs (WACC), and fixed operation and maintenance (O&M) costs, we computed their equivalent annual cost. Table 8 shows the economic parameters used for each type of asset.

Table 9 shows the expected utilization of secondary energy along the years, the number of scenarios in which the system requires secondary and buyback energy, and the number of scenarios in which non-served energy instances occur for the previously described expansion scenarios. Our RC analysis shows that the system requires some secondary energy in every hydro scenario, and all of it under the worst hydrological conditions. Moreover, the existing secondary energy is not enough and the system needs to resort to some buyback energy in every other hydro scenario and, again, all of it under the worst hydrological conditions. Our results uncover the fact that the negotiated curtailment products are alarmingly scarce during drought years and non-negotiated curtailments, i.e. non-served energy, may happen in 3 out of 54 hydro scenarios. Although small, an unexpected outage of 0.35% of total power-intensive demand is unacceptable. Iceland attracts industrial consumers as it provides reliable and cheap electricity. Not providing reliable power could cause shutdown of industries and slowdown future investments in Iceland.

Network contingencies have so far caused most of the unexpected outages in Iceland. Nevertheless, the system operator expects that future transmission network reinforcements will help to mitigate the number, frequency and impacts of contingencies. Although the full implementation of the previously described reinforcements is unrealistic by 2020, our analysis allows us to explore the potential effects of such network reinforcements. We observe that both HO and IO cases would reduce the expected secondary energy requirement by 20% and 25%, respectively, and the system would require secondary energy in every other, instead of every, hydro scenario. Moreover, the system would only demand buyback energy in 1 out of 54 hydro scenarios, and non-negotiated curtailments would disappear. Both reinforcements would increase the transmission capacity among the generation and demand sites in the southwestern, northern and eastern regions, and improve the hydro resources management.

In contrast, our DO sensitivity analysis has produced poor results regarding the security of the system. As the diesel price is higher than the flexibility products price, the system would still demand the same amount of secondary and buyback energy as in the RC analysis. Removing the non-negotiated curtailments would require the installation of 69 diesel stations, with an investment cost higher than that of the previous network reinforcements. Moreover, the diesel stations would be not only expensive, but also mostly idle since their expected utilization would barely reach 250 h in 3 out of 54 hydro scenarios. Finally, Iceland would lose some energy independence, as diesel is not a domestic energy source. Clearly, diesel is not a viable option for maintaining security of supply in the long term. However, few diesel stations could still be used for facing contingencies, maintaining power delivery to critical infrastructure, and helping to restore service after blackouts.

Our analyses indicate that undertaking generation investments before 2030 is critical. Without them, the generation capacity would be insufficient to meet the peak demand by 220 MW. A quick look at the results from the WO-IO, WO-HO, NWO-IO and NWO-HO cases indicate that none of these options significantly outperforms the rest. Both IO and HO reinforcements would equally accommodate the new generation capacity (Fig. 2). Even though the LCOE (Table 7) of the new generation assets is greater than the secondary energy price, new generation capacity would be installed according to economic considerations (Table 9) to reduce buyback energy demand. Consequently, the system would still require all available secondary energy in both the NWO and WO cases, and would reduce the demand of available buyback energy to the point that all of this would only be used in 1 out of 54 hydro scenarios. A minor difference between NWO and WO is that wind generation would need some buyback energy in 4 out of 54 hydro scenarios, but in a small amount. In short, all cases provide similar results in terms of energy security. The wind generation capacity factor, location and capital cost, together with the availability of vast hydro resources to offset the uncertainty about the availability of the former, make wind technology as competitive as hydropower or geothermal technologies in Iceland.

Within our sensitivity analyses, we have identified the most expensive generation investment, which would correspond to h19. Within the GO analysis, we have replaced this hydropower plant at n13 by a gas-fired power plant at n1, where a relevant maritime port and most of the demand are located. Since gas is more expensive than secondary and buyback energy, the system would require the same secondary energy as in the WO-IO, WO-HO, NWO-IO, and NWO-HO cases. However, the system would demand the full amount of buyback energy in every other hydro scenario. Within the CO sensitivity analysis, we removed h19 from the generation portfolio and optimized the amount of buyback energy needed, which must increase from 1.2% to 2.4% to avoid non-negotiated curtailments.

4.5. Economic assessment

All the previous analyses reveal that Iceland needs new investments in generation and transmission assets to face future demand increases, and avoid relevant curtailments and the shutdown of industries. However, the achieved level of security of supply does not vary significantly across options. As a matter of fact, no option leads to non-negotiated curtailments and all of them provide reasonable utilization of secondary and buyback energy.

When diving into the economics of these options (last row in Table 9), we observe that the differences among them within each time scope are also minor, except for the abovementioned both expensive and ineffective DO. The equivalent annual cost of the IO reinforcement amounts to $49 million, while that of the HO reinforcement varies between $33 million (AC overhead line) and $53 million (DC underground line). As both options raise environmental concerns, the result of an environmental impact assessment may tip the scales.

A look at the electricity price shows that the transmission reinforcement increases the transmission tariff $2.43/MWh for the IO reinforcement, and from $1.44/MWh (AC overhead line) to $2.65/MWh (DC underground line) for the HO reinforcement. This increment

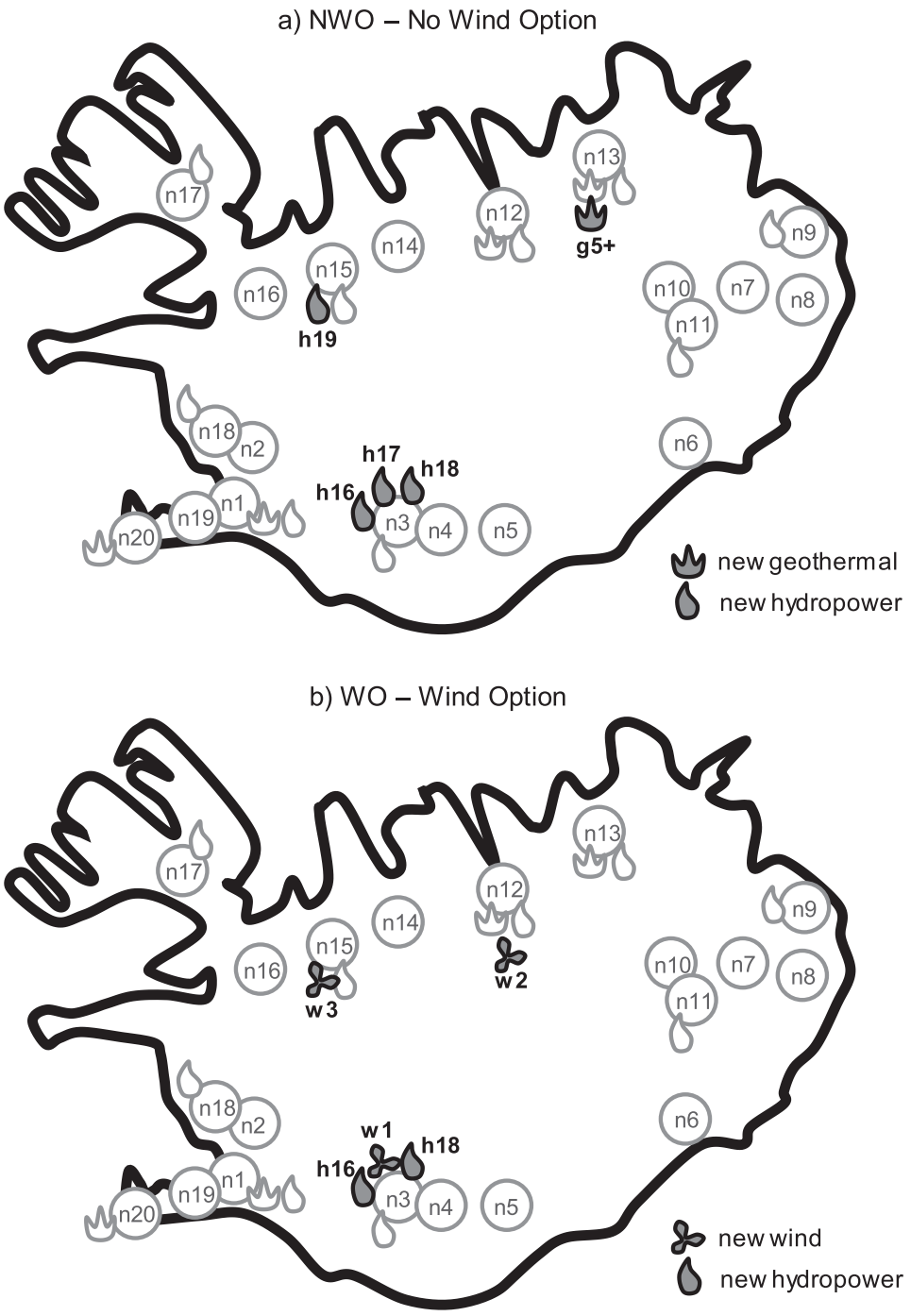

Fig. 2. Generation investments by 2030.

of the tariff, about 10% of current average price, could be acceptable as long as the network reinforcement largely reduces the expected curtailment and eliminates any chance of non-served energy (i.e. non-negotiated curtailment). Put differently, this is the cost of ameliorating the system reliability. Moreover, both network reinforcements improve the management of the hydro resources and reduce the expected annual water spillage by 40 GWh.

On the generation side, the equivalent annual cost of the NWO case is $10 million lower than that of the WO one. This difference represents about 10% of the total investment costs, which may not be enough to clearly favor the NWO. The substitution of the most expensive power plant provides mixed results. Negotiating additional buyback energy, up to 2.4%, may result in equivalent annual savings of about $0.4 million; hence, Iceland should contemplate the option of increasing the demand flexibility. In contrast, installing a new gas-fired power plant results in extra costs of about $7.5 million, plus the loss of energy independence and a deviation from the decarbonization path.

In terms of electricity prices, the NWO implies an increment of about $3.98/MWh, while the electricity price increases by $4.49/MWh under the WO. This means that by 2030, the electricity price could rise between 16% and 18% with respect to current prices due to the generation component. The increment is reasonable and, actually, low if we consider that the Icelandic power demand is expected to grow around 40% by that year. The newly developed renewable resources are more expensive than the existing ones, but under the most expensive scenario, the electricity price due to the generation component would

rise from around $25/MWh to $30/MWh. This figure illustrates how inexpensive renewable generation is, at least within the Icelandic context.

5. Conclusions

Many countries and areas worldwide are in a similar situation to that of Iceland four decades ago, when it started to replace fossil fuels and develop its renewable resources. This remarkable effort has allowed Iceland to gain energy security and decarbonize its energy system. Nowadays, the Icelandic power system is fully renewable, with hydropower and geothermal generation its only energy sources. Yet, energy demand projections and a detailed examination of the Icelandic power system and market structure reveal that Iceland faces significant challenges if it is going to guarantee its security of supply in the future.

We have analyzed security of supply in Iceland focusing on the medium- to long-term temporal dimensions (i.e., firmness, adequacy and strategic energy policy), which mostly determine system configuration, market structure, and resource utilization. For this, we have developed a hydrothermal scheduling model that incorporates DC power flows, generation expansion decisions, and a detailed bilateral contracting structure, which Icelandic generators and consumers typically use for arranging power prices and negotiated curtailments. These bilateral contracts may proliferate in other countries and regions as long as renewable generation is deployed, hence zero prices combined with very high prices.

The results computed using this model suggest that reinforcing the transmission network is necessary to increase the connection capacity between the eastern and southwestern generation and consumption sites and efficiently exploit hydro resources, particularly under drought conditions. The installation of diesel stations to defer network reinforcements would be more expensive and less effective than the network reinforcements. On the generation side, Iceland would need to develop new hydropower and geothermal projects. Our analysis reveals that wind would be as competitive as hydropower and geothermal generation due to its relatively high capacity factor, geographic dispersion and low capital cost. The existing large hydropower facilities would help to deal with wind intermittency. Increasing the amount of negotiated curtailments could defer the most expensive generation investments, but this alternative would require the compliance of energy-intensive consumers. Finally, our results show that returning to the use of fossil fuels (i.e., gas) would be more expensive and less effective than installing renewable generation.

This approach is applicable to other countries and areas. First, the public authorities, with input from the main stakeholders (private companies, public opinion, etc.), must establish a strategic energy policy that should define the guidelines as to what type of energy system they are pursuing. For instance, Icelanders have decided to attract energy intensive consumers by enabling secure and renewable energy resources, such as water, geothermal and, lately, wind. This process requires an analysis of the energy potential of the area with particular emphasis on the renewable resources if the objective is decarbonizing. Second, achieving adequate levels of generation and transmission capacity to comply with the strategic energy policy requires attracting private capital. Accordingly, public authorities must concede permits to develop new infrastructures when these show that they are economically viable. For example, our case study has shown which transmission reinforcement options are of interest and which generation projects are preferred. Third, markets and regulations guide companies and consumers to guarantee that the installed capacity is firm, i.e. is ready when needed, and/or that other resources are available to guarantee the security of supply. Our model has indicated the optimal Icelandic hydro operation and curtailment strategies to minimize system costs.

Regulators, system and/or market operators, producers and large consumers alike could use the model, although they typically would be pursuing different objectives. A regulator could evaluate how close to the minimum cost solution the producers' operation and curtailment decisions are. System and/or market operators could foresee difficulties and provide signals to producers and consumers to modify their behavior and avoid major problems. Producers could optimize the utilization of their generation resources (e.g. hydro reservoir management or plant maintenance scheduling); while large consumers could foresee scarcity periods, and value and negotiate curtailments.

At last, we briefly mentioned at the beginning of this paper that distributed energy systems could test the Icelandic bilateral contracting structure to develop their market and pricing mechanisms. This is an interesting future research guideline within the context of high penetration of technologies with zero marginal cost, as in Iceland, since the traditional (marginal-cost) bidding system of liberalized electricity wholesale markets may neither allocate resources adequately nor provide economic signals for investments. How to adapt current market mechanisms to future distributed systems and what type of pricing strategy could adopt the distributed resources are questions that need to be addressed in the near future.

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Conflict of interest

None.

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